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MEMORANDUM

S.C. PUBLIC SERVICE COMMISSION
MAY 12 2008
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TO: The Honorable Charles L.A. Terreni
Administrator and Chief Clerk - PSCSC

FROM: Michael W. Chiasson

DATE: May 8, 2008

RE: Duke Market Monitoring Report, Docket # 2005-210-E

Attached please find the Duke Market Monitoring reports for the period of January 2008 through March 2008. Let me know if you have any questions.

Regards,

Mike

Director of Operations Monitoring
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QUARTERLY MARKET MONITORING REPORT
ON
DUKE ENERGY CAROLINAS, LLC

January 2008 through March 2008

Issued by:

Potomac Economics, Ltd.
Independent Market Monitor

Table of Contents

List of Figures

I. OVERVIEW

This transmission monitoring report addresses the period from January 2008 through March 2008 for Duke Energy Carolinas, LLC (formerly Duke Power, a division of Duke Energy Corporation) ("Duke" or "the Company"). For the purpose of increasing confidence in the independence and transparency of the operation of the Duke transmission system, Duke proposed and FERC accepted in Docket No. ER05-1236-00 the establishment of an "Independent Entity" to perform certain OATT-related functions and a transmission monitoring plan that calls for an "independent transmission service monitor". The Midwest ISO was retained as the Independent Entity ("IE"), and Potomac Economics was retained as the independent transmission service monitor.

The scope of the independent transmission service monitor is established in the transmission monitoring plan. The plan is designed to detect any anticompetitive conduct from operation of the company's transmission system, including any transmission effects from the company's generation dispatch. It is also intended to identify any rules affecting Duke's transmission system which results in a significant increase in wholesale electricity prices or the foreclosure of competition by rival suppliers. As stated in the plan:

> The Market Monitor shall provide independent and impartial monitoring and reporting on: (1) generation dispatch of Duke Power and scheduled loadings on constrained transmission facilities; (2) details on binding transmission constraints, transmission refusals, or other relevant information; (3) operating guides and other procedures designed to relieve transmission constraints and the effectiveness of these guides or procedures in relieving constraints; (4) information concerning the volume of transactions and prices charged by Duke Power in the electricity markets affected by Duke Power before and after Duke Power implements redispatch or other congestion management actions; (5) information concerning Duke Power's calling for transmission line loading relief ("TLR"); and (6) the information provided by Duke Power used to perform the calculation of Available Transmission Capability ("ATC") and Total Transfer Capability ("TTC").

To execute the monitoring plan, Potomac Economics routinely receives data from Duke that allows us to monitor generation dispatch, transmission system congestion, and the Company's response to transmission congestion (both its operational response and its business activities). We also collect certain key data ourselves, including OASIS data and market pricing data.

The purpose of this report is to present the results of our monitoring activities and significant events on the Duke system[1] from January 2008 through March 2008.

A. Market Monitoring

Potomac Economics performs the market monitoring function on a regular basis, as well as performing periodic reviews and special investigations. Our primary market monitoring is conducted by way of regular analysis of market data relating to transmission outages, congestion, and system access. This involves data on transmission outages, transmission reservation requests, Available Transfer Capability ("ATC"), transmission line loading relief ("TLR") and curtailments or other actions taken by Duke to manage congestion. Analyses of this data aid in detecting congestion and whether market participants have full access to transmission service.

In addition to the regular monitoring of outages and reservations, we also remain alert to other significant events, such as price spikes, major generation outages, and extreme weather events that could adversely affect transmission system capability and give rise to the opportunity for anticompetitive conduct.

Our periodic review of market conditions and operations is based on data Duke provides, as well as other data that we routinely collect. Our review consists of four parts. First, we evaluate regional prices and transactions to provide an assessment of overall market conditions. Second, we summarize transmission congestion and the use of schedule curtailments in order to detect potential competitive problems. Congestion is identified by TLR events and schedule curtailments[2] on Duke's transmission system. Third, we evaluate the disposition of transmission service requests and TTC to analyze transmission

1 As allowed for in the monitoring plan, certain anomalous findings related to general market conditions, TTC, and transmission outages were shared with Duke to obtain clarification prior to submission to FERC and the state commissions.

2 When we refer to schedule curtailments, we include TLR events because schedule curtailments are the main method used under the TLR procedures to manage congestion.

access and to detect events on the Duke system that require closer analysis. Finally, to monitor for anticompetitive conduct, we examine periods of congestion and evaluate whether Duke operating activities are consistent with anti-competitive conduct. The operating activities that we evaluate are wholesale purchases and sales, generation dispatch and availability, and transmission availability.

In addition to our periodic reviews, we may from time-to-time be asked to or deem it necessary to undertake a special investigation in response to specific circumstances or events. No such events occurred during the time period of this report.

B. Summary of Quarterly Report

There were no notable conditions that adversely affected the market this quarter.

1. Wholesale Prices and Transactions

Prices. We evaluate regional wholesale electricity prices in order to provide an overview of general market conditions. Over the course of the study period, electricity prices have been variable and exhibited a moderate correlation with peak load and a relatively strong correlation with natural gas prices. This pattern is not unusual for the colder winter months.

Sales and Purchases. Duke engages in wholesale purchases and sales of power on both a short-term and long-term basis. Duke was a short-term net [redacted] for the study period. Duke short-term wholesale [redacted] volumes initiated during the study period exceeded short-term wholesale [redacted] volumes by more than [redacted] to [redacted] At a broad level, the fact that Duke's short-term [redacted] exceed its short-term [redacted] suggests that if Duke does have [redacted].

2. Transmission Congestion

We use TLR events in the vicinity of Duke and schedule curtailments initiated by Duke to identify periods of congestion. Duke manages transmission congestion with generation redispatch, transmission system reconfiguration, and schedule curtailments.[3] Of these, schedule curtailments have the most direct impact on market access and outcomes. Duke operates primarily on a contract path basis. A common situation in which Duke uses curtailments is when unscheduled firm reservation rights are released to the market and scheduled for non-firm use, but are then displaced when the higher priority firm reservation holders subsequently submit schedules. The displaced non-firm schedules are curtailed. Curtailments also can occur when the paths reach their contract limits even though they may not be heavily loaded with physical flow. During the period of study, there were 42 curtailments initiated by Duke and twelve TLR events in the region.

All curtailments regardless of their basis are important because they have the same impact in reducing transmission access. Only schedules curtailed based on physical flow, however, are potentially influenced by generation operations. We analyzed the impact of Duke's generation operations on the twelve TLR events initiated by PJM. We did not find that Duke's dispatch of generation unjustifiably contributed to the TLR events.

3. Transmission Access

We evaluate the patterns of transmission requests and their disposition to determine whether market participants have had difficulty accessing Duke's transmission network. If requests for transmission service are frequently denied unjustifiably, this may indicate an attempt to exercise market power. The volume of accepted requests was comparable to the previous quarter. The approval rates were also relatively high, averaging 99.4 percent over the period of study. Given the high volume of service sold and the low level of refusals, we do not find a pattern in the disposition of transmission requests that indicates restrictive access to transmission.

For the period of study, we identified PJM to Duke and Southern Company to Duke as key paths on which to evaluate TTC based on refused transmission service requests and

3 We use the term schedule loosely in this context. It is actually e-tags that are curtailed. Each e-tag represents a physical sequence and time series of schedules. Therefore, one e-tag may have multiple schedules comprising it. Also, sometimes the same e-tag is curtailed more than once.

dispatch) occurs and causes congestion, further analysis is warranted to determine whether the Company's conduct raises competitive concerns.

Using an estimated supply curve, we analyze Duke's actual dispatch to determine whether the actual dispatch departed significantly from what we estimate to be the economic dispatch. We then evaluate the contribution that the out-of-merit dispatch makes to flows on congested transmission paths to determine if congestion was either created and/or exploited by Duke. Our investigation into congestion events found that the potential impact of out-of-merit generation dispatch was minimal. In fact, the highest increased flow on congested paths from out-of-merit generation dispatch was under 2 MW. Thus, we conclude that the out-of-merit dispatch did not adversely affect market outcomes.

We also conducted an analysis of potential economic and physical withholding to further evaluate generation operations. With one exception, indicators of potential economic and physical withholding were moderate and not indicative of anticompetitive conduct. The exception was an 862 MW output gap. However, this event was caused by a night-time spike in PJM prices while several units were starting up in preparation for meeting the next day's load. We did not consider this as an indication of anticompetitive conduct.

Transmission Availability. Finally, we evaluate Duke's transmission outage events in order to determine whether these events may have unduly impacted market outcomes during the study period. Some of these events affected the Duke to TVA interface. Our analysis of these events indicated that they were justified. We found no outages of Duke's transmission assets that led to schedule curtailments. Thus, we found no evidence of anticompetitive conduct.

5. Conclusions

Our analysis did not indicate any potential anticompetitive conduct from operation of the company's transmission system or generation.

C. Complaints and Special Investigations

We have not been contacted by the Commission or other entities regarding any special investigation into Duke's market behavior, nor have we detected any conduct or market conditions that would warrant a special investigation.

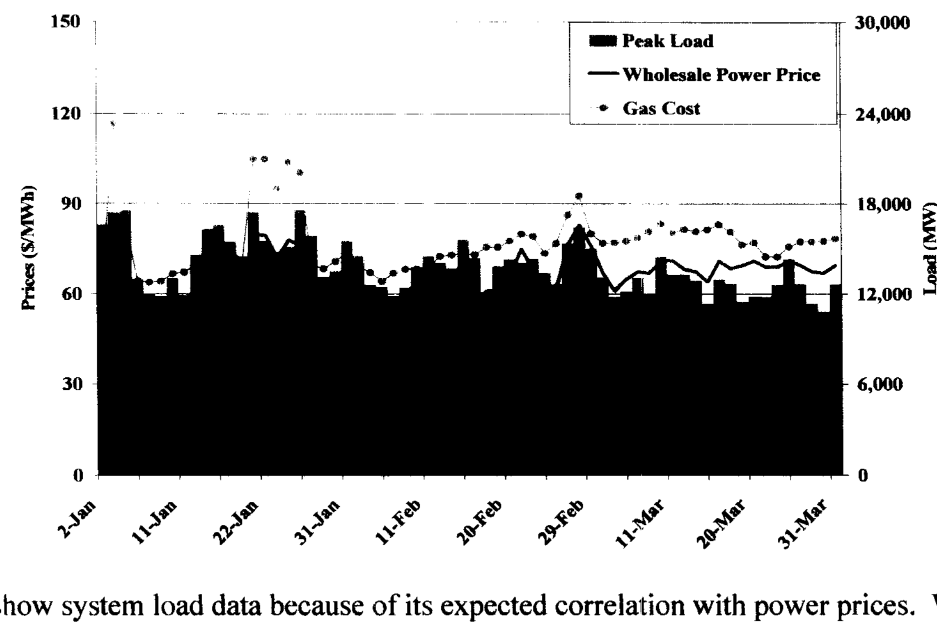
II. Wholesale Prices and Transactions

A. Prices

We evaluate regional wholesale electricity prices in order to provide an overview of general conditions in the market in which Duke operates. Examining price movements can provide insight into specific time periods that may merit further investigation, although they are not definitive indicators of anticompetitive conduct.

Duke is not part of a centralized wholesale market in which transparent spot prices are produced. Wholesale trading in the areas in which Duke operates is conducted under bilateral contracts. Bilateral contract prices are collected and published by commercial data services such as Platts, which we use for this report. Platts publishes prices at various pricing points, including a price for the VACAR (Virginia, Carolinas) sub region of the South East Reliability Council ("SERC"), which includes Duke's control area. Figure 1 shows the bilateral contract prices for VACAR along with other market indicators.

Figure 1: Wholesale Power Prices and Peak Load
January 2008 through March 2008

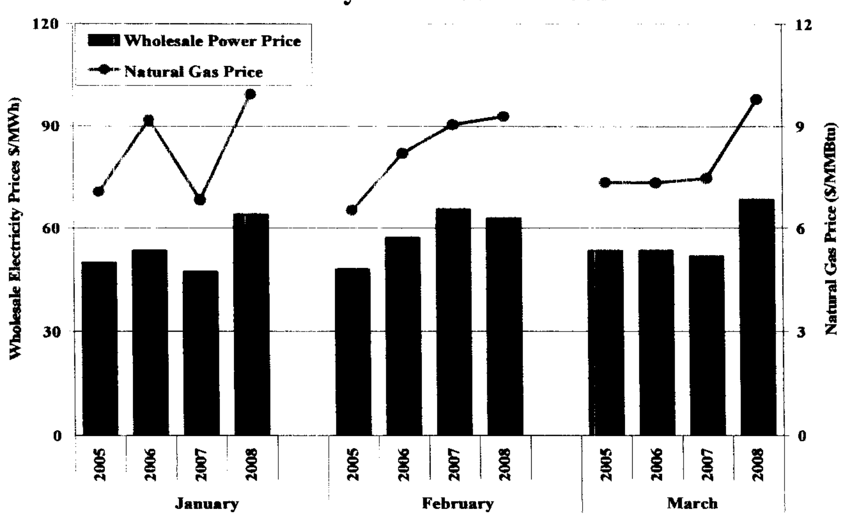


We show system load data because of its expected correlation with power prices. We show natural gas prices because natural gas-fired units are most often the marginal unit supplying the grid, and because fuel costs comprise the vast portion of a generating unit's marginal costs. We use the daily price of natural gas deliveries by Transco at its Zone 5 location, a main pricing point for natural gas purchases by Duke. We translate this natural gas price to a power cost assuming an 8,000 btu/kWh heat rate. This number roughly corresponds to the fuel cost portion of the operating cost of a natural gas combined cycle power plant, which should generally correspond to the competitive price for power.

Prices ranged from $40/MWh to $83/MWh over the study period. The correlation between power prices and load was moderate (50 percent) and the correlation between power prices and natural gas prices was strong (76 percent). This pattern is not unusual for the colder winter months.

The next analysis compares the average VACAR power prices for each month in the study period with the corresponding month of the previous three years. Results are shown in Figure 2 together with the average of the daily Transco Zone 5 natural gas prices. As the figure shows, electricity prices have generally been correlated with natural gas prices over time.

Figure 2: Trends in Monthly Electricity and Natural Gas Prices
January 2005 – March 2008



Overall, our evaluation of wholesale electricity prices in the Duke region did not indicate a time period that merits particular attention based on pricing patterns.

B. Sales and Purchases

Duke engages in wholesale purchases and sales of power. These transactions are both firm and non-firm in nature. Figure 3 summarizes Duke's sales and purchase activity for trades that were initiated during the study period. We consider only short-term trades because we are interested in transactions that could have allowed Duke to benefit from any potential market abuse during this time period. Short-term transactions include all transactions that are done in the day-ahead or real-time markets. Longer-term transactions generally occur at predetermined prices that would not be directly affected by transitory periods of congestion. Additionally, short-term transaction prices are good indicators of wholesale market conditions during periods of congestion.

Figure 3: Summary of Duke Sales and Purchases
First Quarter of 2008

Redacted

As the figure shows, Duke's short-term [redacted] Another noteworthy feature is [redacted] we evaluate the prices during congested periods in Section V.A to detect potential anticompetitive conduct.

III. TRANSMISSION CONGESTION

A. Overview

Duke is located in the SERC region of the North American Electric Reliability Council ("NERC"). NERC is certified as the Electric Reliability Organization ("ERO") in the United States as of July 20, 2006. SERC is divided geographically into five sub-regions that are identified as Entergy, Gateway, Southern, TVA, and VACAR. VACAR is further divided into two intraregional coordination groups including VACAR North and VACAR South for the establishment of Reliability Coordinators ("RC"). Duke is within the VACAR South coordination group along with five other balancing authorities: Progress Energy Carolinas, Inc., South Carolina Electric & Gas Company, South Carolina Public Service Authority (Santee Cooper), Southeastern Power Administration, and Yadkin (a division of Alcoa Power Generation Inc).

Procedures to manage transmission congestion are implemented by the VACAR South Reliability Coordinator. The activities covered in these procedures include performing day-ahead and real-time reliability analysis, working with participants to correct System Operating Limit ("SOL") and Interconnection Reliability Operating Limit ("IROL") violations, and managing TLR events.

The VACAR South Reliability Coordinator utilizes an "Agent" to perform Reliability Coordination tasks. Duke, in addition to being a member of the VACAR South coordination group, is contracted to serve as Agent to perform the duties of Reliability Coordinator for itself and the other five VACAR South member companies. The transmission monitoring plan calls for monitoring Duke's operation of its transmission system to identify anticompetitive conduct, including conduct associated with system operations and reliability coordination.[4] Our monitoring of such conduct is limited to conduct associated with Duke's transmission system and does not extend to Duke's activities as Agent for the VACAR South Reliability Coordinator.

[4] See Transmission Service Monitoring Plan, Section 1.2.

B. Transmission Congestion

We monitor Duke for potential anticompetitive operation of generation or transmission facilities that may create transmission congestion or otherwise create barriers to rival companies' access to the markets. Congestion in the operating horizon is identified through real-time contingency analysis ("RTCA"). In this process, line-loadings are monitored to keep them within ranges whereby a system outage or "contingency" can be safely sustained. If the line-loadings exceed this safe range (called the system operating limit or "SOL"), then the lines are relieved[5] through generation redispatch, reconfiguration, schedule curtailments, and/or load reduction.[6]

Congestion between balancing authorities is monitored and managed through the use of Transmission Loading Relief (TLR) procedures. These procedures invoke schedule curtailments, system reconfiguration, generation re-dispatch, and load shedding as necessary to relieve congestion by reducing flows below the first-contingency transmission limits on all transmission facilities. Duke's general practice is to curtail schedules and re-dispatch generation as needed to manage congestion without invoking TLR procedures, but Duke can impact or be impacted by TLR events invoked by neighboring areas.

Schedule curtailments can constitute anticompetitive conduct if they are not justified. They cause an immediate reduction in market access that could affect market outcomes. Accordingly, these congestion events are the basis for our screening of Duke's generation and transmission operations.

For the purposes of our analysis, we consider two types of schedule curtailments. One we refer to as "flow-based curtailments", which are curtailments to accommodate the actual physical flows on facilities as identified by the RTCA. TLR events are included with flow-based curtailments when we conduct our analysis of operating activities. The other is "contract-path-based curtailments" which are not related to physical flows but rather to contract path limits. Contract-path-based schedule curtailments may be implemented to stay within contract limits even though the path may not be physically

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5 Some contingency overloads do not require action to be taken because they do not have the potential to cause cascading outages, substantial loss of load, or major equipment damage.

6 System reconfiguration actions may include opening tie line breakers, which can cause TTC to go to zero, inducing schedule curtailments.

congested. While this has the same effect on market access, these curtailments are not caused by the operation of generation.

Contract-path based curtailments are implemented when transmission conditions reduce total transfer capability below the level of existing schedules on the contract path, which results in the curtailment of non-firm and possibly firm schedules. Contract-path based curtailments are also the result of non-firm service being displaced to accommodate a schedule under a firm reservation. Since these conditions are not affected by generation operations, we only use the flow-based curtailments in our analysis of generation operations.

During the period of study, there were 42 curtailments initiated by Duke and twelve TLR events in the region, initiated by PJM. Five curtailments were due to reductions in TTC as a result of the next-day study. Thirty four curtailments were due to service being pre-empted by higher-priority service. Three curtailments were the result of the PJM interface being overscheduled.[7] As mentioned previously, we included the twelve nearby TLR events initiated by PJM in our analysis. These congestion events will be evaluated later in the report.

[7] An interface can be overscheduled if the sum of the schedules exceed the contract path limit. This can occur due to the TTC value being lowered after schedules have been accepted.

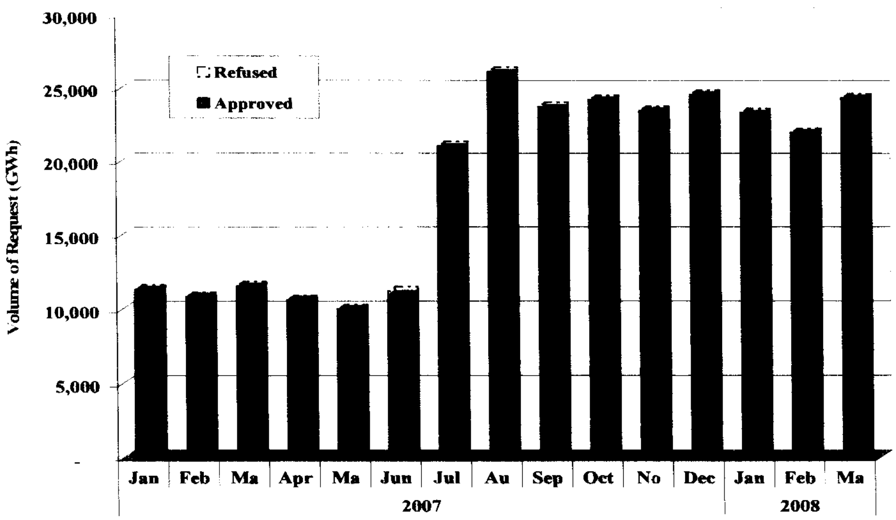
IV. TRANSMISSION ACCESS

A main component of the transmission monitoring function is to evaluate transmission availability on the Duke system. In this section, we evaluate access to transmission by analyzing the disposition of transmission requests. The patterns of transmission requests and their disposition are helpful in determining whether market participants have had difficulty accessing Duke's transmission network.

In order to make this evaluation, we calculate the volume of requested capacity that spanned the time period under study. For example, if a request was approved in January for service in June, we categorize that as an approval for June. Because requests vary in magnitude and duration, we assign a total monthly volume (GWh) associated with a request, which provides a common measure for all types of requests. Hence, a yearly request for 100 MW has rights for every hour of the month for which the request spans, just a like a monthly request. A request covering less than the entire month is assigned the hours between its stop and start date.

Figure 4 shows the breakdown of transmission service requests in each month from January 2007 through March 2008 and summarizes the disposition of the requests.

Figure 4: Disposition of Requests for Transmission Service on the Duke System January 2007 - March 2008



The figure shows that the total volumes of approved requests during the study period have increased substantially compared to the same months from the year before. This is not consistent with a hypothesis of more restrictive access.

The volume of approved and refused requests over the course of the study period was comparable to the previous quarter. Most importantly, however, the volume of approved transmission service increased substantially from first and second quarters of 2007. Although it is not obvious from the figure, the refusal volume averaged only 132 GWh during the first quarter of 2008, which is comparable to the average refusal volume of 128 GWh during the fourth quarter of 2007. Additionally, the approval rate of transmission service requests was relatively high over the study period, averaging 99.4 percent. Given that the quantities of transmission service sold have increased and approval rates have remained high, there is no evidence that Duke has restricted access to transmission capability.

To evaluate the disposition of transmission requests further, we compare the volume of transmission requests over the study period by increment of service to the requests from the corresponding period a year prior. This comparison is shown in Figure 5.

Figure 5: Disposition of Transmission by Duration of Service

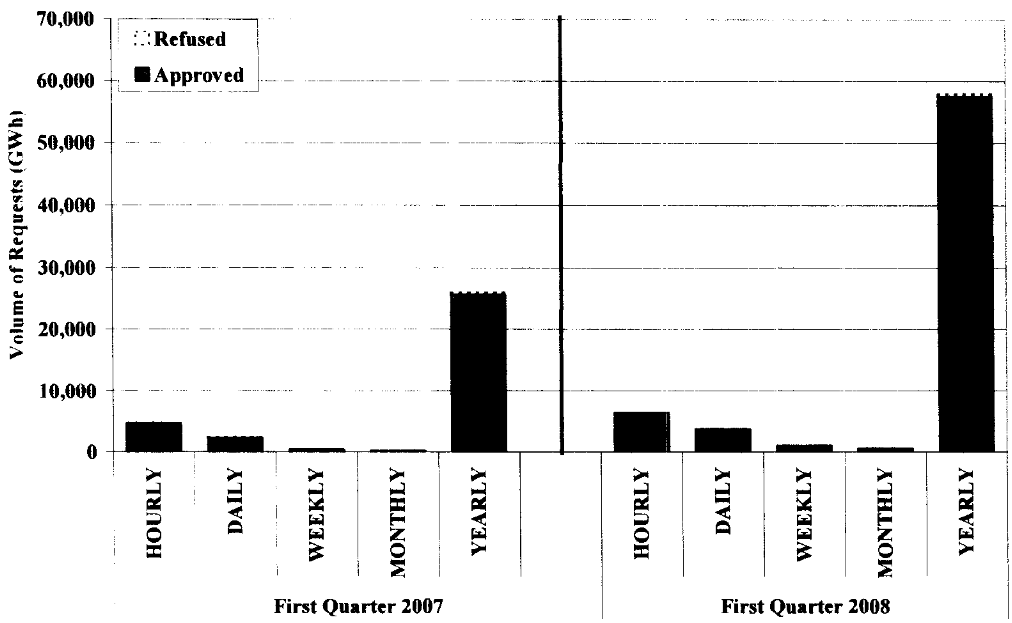
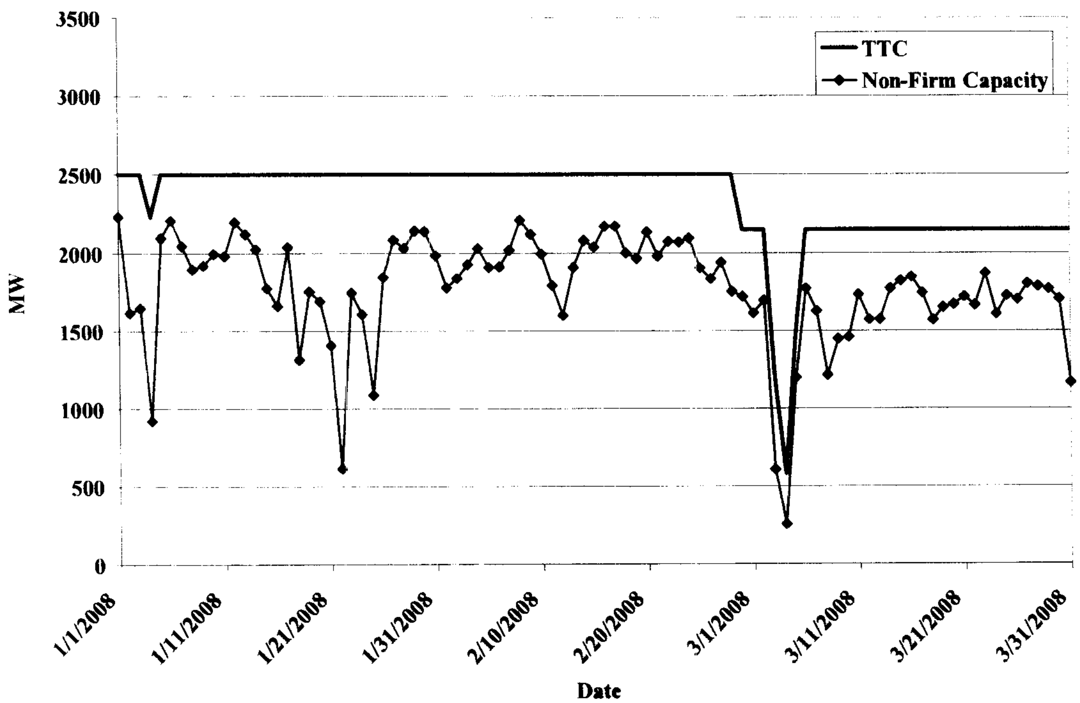


Figure 5 indicates an increase in approvals in every category of service, with the largest increase being for the yearly category of service. The increases in approval volumes for every category of service further supports our conclusion that transmission access has not become more restrictive.

Our next analysis focuses on TTC for specific contract paths. Based on refused transmission service requests ("TSRs") and schedule curtailments, Duke to PJM and Southern Company to Duke stood out as key paths. The concern on these paths are events when there is a drop in TTC that is of sufficient magnitude that the non-firm ATC is reduced to zero. Our analysis is shown in Figure 6 and Figure 7.

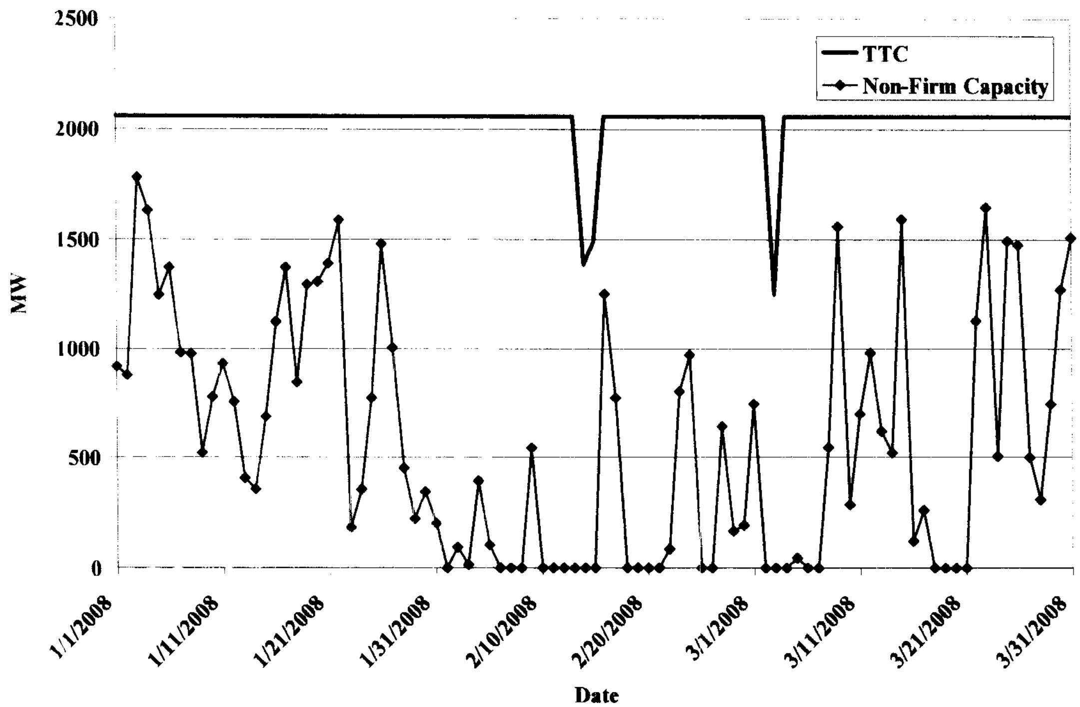
The figures show TTC and non-firm ATC. On the Southern Company to Duke path, there was a single large drop in TTC on March 4, 2008 that lasted two days. However, the non-firm ATC remained above zero during the two day event. For this event, the TTC was limited by transmission elements in the Southern Company system.

Figure 6: Southern Co. to Duke Daily Minimum of Hourly Capacity



On the Duke to PJM path (shown in Figure 7), there were three instances when TTC dropped sufficiently and caused non-firm ATC to be reduced to zero. We reviewed these events and found that the IE incorrectly posted the TTC for PJM to Duke as Duke to PJM on March 3, 2008. The IE indicated that they were reviewing procedures that could prevent these types of mis-postings in the future. The TTC values for February 14, 2008 and February 15, 2008 were both set by day-ahead studies performed by the IE. We reviewed the real-time flows on the limiting transmission system elements and found that the real-time flows never exceeded 70 percent of the operating limit used in the day-ahead TTC studies.[8] Thus, it appears that the forecasted flows used in the day-ahead study significantly overstated the actual flows. Accordingly, posting zero hourly non-firm capacity on the path can contribute to underutilization of the transmission system in real-time by hundreds of MWs. We plan to further review with Duke and the IE the process for establishing non-firm hourly ATC.

Figure 7: Duke to PJM Daily Minimum of Hourly Capacity



[8] The limiting transmission elements were: Eno-Pleasant Garden 230 kV line for the loss of Park wood-Pleasant Garden 500 kV line.

PJM to SOCO did not stand out as a key path during the period of study. However, our evaluation of sales and purchase prices suggested that the TTC reduction that resulted in a curtailment on this path on March 3, 2008 warranted investigation.[9] The TTC value was established consistent with the tariff. The IE determined the most limiting element of the PJM to Duke segment and the Duke to SOCO segment. In this case, the limiting segment was PJM to Duke and the limiting element was on the SOCO system. There appeared to be a synergy between the two segments, in that the PJM to Duke segment loaded the SOCO constraint, but the Duke to SOCO segment unloaded the SOCO constraint. Hence, it is possible that an analysis of the entire Duke to SOCO path would not have indicated that the curtailment of this e-tag was necessary. Therefore, we recommend that the IE consider whether it is feasible to evaluate TTC on entire paths when implementing curtailments.

[9] This was the curtailment of e-tag PJM_CRGL1AAP0304W_SOCO.

V. Monitoring for Anticompetitive Conduct

In this section, we report on our monitoring for anticompetitive conduct. The market monitoring plan calls for identifying anticompetitive conduct, which includes conduct associated with the operation of either Duke's transmission assets or its generation assets that can create transmission congestion or erect barriers to rival suppliers, thereby raising electricity prices. To identify potential concerns, we analyze Duke's wholesales sales in the first subsection below, its dispatch of generation assets in the second subsection, and Duke's transmission operations in the third subsection.

A. Wholesale Sales

We examine sales data to determine whether the prices at which Duke sold power may raise concerns regarding anticompetitive conduct that would warrant further investigation. We are particularly interested in periods when transmission congestion arises. If Duke were engaging in anticompetitive conduct to create the congestion, it could potentially benefit by making sales at higher prices in constrained areas or purchases at lower prices adjacent to constrained areas. We examined the short-term bilateral transactions made by Duke using Duke internal sales records. We focus on short-term transactions because anticompetitive conduct is likely to be more successful in the short-term market.

Competition is facilitated by the ability of rivals to gain market access by reserving and scheduling transmission service. Access will be limited if ATC is unavailable, transmission requests are refused, or schedules are curtailed. Curtailments are also an indicator of congestion because they can be made when a path is over scheduled or physically overloaded. If Duke's ability to curtail schedules is being abused, we would expect to see systematically higher prices for sales or lower prices for purchases coincident with curtailments.

Recall that curtailments can be flow-based (i.e., the result of flows exceeding the system operating limit), or contract-path-based (i.e., the result of contract-path reservations exceeding the path rating). For our analysis of Duke's sales, we use both types of curtailments. This is reasonable because both types of curtailments reduce market access.

Moreover, Duke has the direct ability to affect both flow-based curtailments and contract-path-based curtailments. It can affect flow-based curtailments through operating activities and it can affect contract-path-based curtailments by unjustifiable schedule reductions. By screening the curtailment data against sales activities, we can focus attention on events that merit further inquiry.

Figure 8 shows the daily average prices received by Duke for short-term bilateral sales and purchases. The figure also indicates days when curtailments occurred that could have potentially benefited Duke's position in the short-term bilateral markets. A curtailment may impact system flows at market delivery points to the benefit of Duke's net position at those delivery points.[10]

Figure 8: Prices for Duke Sales and Purchases
January 2008 – March 2008

Redacted

The weighted average daily prices of Duke's sales range between $[redacted]/MWh and $[redacted]/MWh. The volume-weighted average daily sales price was $[redacted]/MWh. On days

[10] The relationship between constrained paths and market delivery points is determined through shift factors, which are the portion of power injected at the market delivery point that flows over the constrained transmission path.

with curtailments that may have benefited Duke's net sales position, the average sales price was also $[redacted]/MWh. The weighted average daily price of Duke's purchases was in the range between $[redacted]/MWh and $[redacted]/MWh. The volume-weighted average daily purchase price was $[redacted]/MWh. On days with potentially beneficial curtailments, the average purchase price was also $[redacted]/MWh.

Aside from a sale made on [redacted] Duke's sales prices on days with the highlighted curtailments were consistent with prices on the preceding and subsequent days when no such curtailments were made. Likewise, aside from a purchase made on [redacted] the Duke's purchases prices on days with the highlighted curtailments were consistent with prices on the preceding and subsequent days when no such curtailments were made.

With respect to the two days considered as exceptions, we found that the [redacted] on [redacted] were for delivery points in [redacted] and [redacted], which are fairly distant from the limiting element for [redacted] into [redacted][11] The element was not found to be limited by Duke transmission outages as addressed in the last section of this report. It was also not affected by Duke generation dispatch, since the limit was based on the day-ahead forecast for the contract path and not real-time flows. The [redacted] on [redacted] was into the [redacted] market while Flowgate [redacted][12] was in TLR 3b. We found that this TLR was called by [redacted] and was not significantly impacted by Duke's generation dispatch, as addressed in the next section. Accordingly, these transactions are not indicative of anticompetitive conduct.

B. Generation Dispatch and Availability

To further evaluate whether Duke's conduct raises any anticompetitive concerns, we examine the company's generation dispatch to determine the extent to which congestion may have been the result of uneconomic dispatch of generation by Duke. We conduct two analyses. We first determine the hourly quantities of out-of-merit dispatch and the

11 [redacted]

12 Flowgate [redacted] is [redacted] kV line for the loss of the [redacted] kV line.

degree to which the out-of-merit dispatch contributes to flows on congested transmission paths. If the contribution is significant, further investigation of these times may be warranted. We use flow-based curtailments because, as explained more below, these types of curtailments (as opposed to contract-path-based curtailments) are the ones that would result from unjustified out-of-merit dispatch. Second, we examine the "output gap", which measures the degree to which Duke's generation resources were not fully scheduled when prevailing prices exceeded the marginal cost of running the unit.

1. Out-of-Merit Dispatch and Curtailments

Congestion can be a result of limits on the transmission network when utilities dispatch their units in a least-cost manner. This kind of congestion does not raise competitive concerns. If a departure from least-cost dispatch ("out-of-merit" dispatch) is unjustifiable and causes congestion, it raises potential competitive concerns.

We pursue this question by measuring the out-of-merit dispatch on the Duke system. In our analysis, we consider a unit to be out-of-merit when it is dispatched when a lower-cost unit is not fully loaded at the same time. To identify out-of-merit dispatch, we first estimate Duke's marginal cost curve or "supply curve".[13] We use incremental heat rate curves, fuel cost, and other variable operations and maintenance cost data provided by Duke to estimate marginal costs. This allows us to calculate marginal costs for Duke's units. We order the marginal cost segments for each of the units from lowest cost to highest cost to represent the cost of meeting various levels of demand in a least-cost manner. For our analysis, the curve is re-calculated daily to account for fuel price changes, planned maintenance outages, and planned deratings.

Figure 9 shows the estimated supply curve for a representative day during the time period studied.

[13] We use the term marginal cost loosely in this context. The value we calculate is actually the *marginal running cost* and does not include opportunity costs, which may include factors such as outage risks or lost sales in other markets.

Figure 9: Duke Supply Curve

Redacted

Note: Excluding Approximately 11,900 MW of Nuclear and Hydro Capacity.

The dispatch analysis excludes nuclear and hydro units because their operation is not primarily driven by current system marginal operating costs. Nuclear resources rarely change output levels and the opportunity costs associated with hydroelectric resources make it difficult to accurately estimate their costs.

As the figure shows, the marginal cost of supply increases as more units are required to meet demand, as expected. The highest marginal cost is over $[redacted]/MWh. We use each day's estimated marginal cost curve as the basis for estimating Duke's least-cost dispatch for each hour in the study period.

In general, this will not be completely accurate because we do not consider all operating constraints that may require Duke to depart from our estimate of least-cost dispatch. In particular, this analysis does not model generator commitments, assuming instead that all available generators are online. While market monitoring resources could have been expended to refine the estimated generator commitment and dispatch to make it correspond more closely to actual operating parameters (i.e., start costs, run-time and down-time constraints, etc.), we believe this simplified incremental-operating-cost approach is adequate to detect instances of significant out-of-merit dispatch that would have a material effect on the market.

When a unit with relatively-low running costs is justifiably not committed, our least-cost dispatch will overstate the out-of-merit quantities because it will identify the more expensive unit being dispatched in its place as out-of-merit. This may result in higher levels of out-of-merit dispatch during low-load periods when it is not economic to commit certain units.

Other justifiable operating factors that cause the out-of-merit dispatch to be overstated are energy limitations and ancillary services. An example of an energy limitation is a coal delivery problem that prevents a coal plant from being fully utilized. Because the coal plant is still capable of operating at full load for a shorter time period, the condition does not result in a planned outage or derating. The necessity to operate the plant at reduced load to conserve coal can cause the out-of-merit values to be overstated.

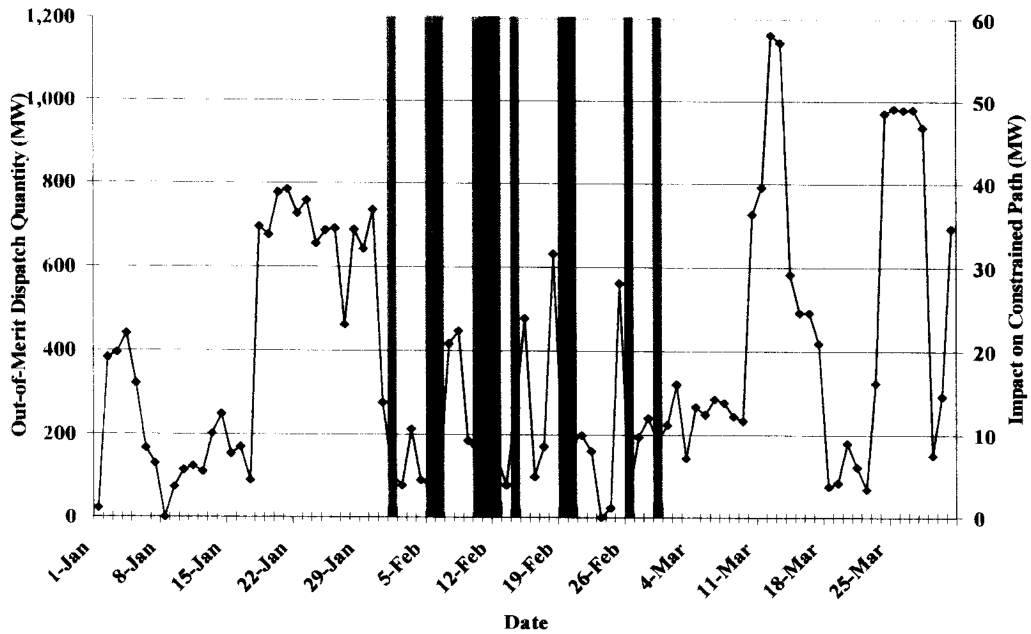
Ancillary services requirements such as spinning reserves, system ramp rate limitations, and AGC control requirements can make it operationally necessary to dispatch a number of units at part load rather than having the least expensive unit fully-loaded. These operational requirements can cause the out-of-merit values to be overstated. The out-of-merit quantities include units on unplanned outage since a sudden unplanned outage may be an attempt to uneconomically withhold generation from the market.

Overall, our analysis will tend to overstate the quantity of generation that is truly out-of-merit. Accordingly, the accuracy of a single instance of out-of-merit dispatch is not as important as the trend or any substantial departures from the typical levels.

In our analysis, we seek to identify days with significant out-of-merit dispatch that coincides with transmission congestion. Congestion is indicated by flow-based schedule curtailments. Flow-based curtailments are those that are taken close to real-time in order to prevent physical flows from exceeding system operating limits. Out-of-merit dispatch can be used to affect these flows and create the need for curtailments; potentially limiting competition in specific locations. Contract-path based curtailments, on the other hand, are the result of reserved rights on the contract paths and are unaffected by real-time dispatch.

Figure 10 shows the daily maximum "out-of-merit" dispatch for the peak hours of each day in the study period. Also shown in the figure are days with flow-based curtailments represented as blue bars. For these days, the out-of-merit dispatch displayed is the maximum taken over just the hours of the day with curtailments. The red bars show the maximum impact of the out-of-merit dispatch on the congested path(s) associated with the curtailment(s) for that hour.

Figure 10: Out-of-Merit Dispatch and Congestion Events
January 2008 – March 2008



As the figure shows, there were no days when out-of-merit dispatch contributed significantly to increased flow over congested paths during the study period. In fact, the highest increased flow was only just under two MW. As such, we found that there were no significant effects on transmission constraints due to out-of-merit dispatch. Consequently, we do not find evidence of anticompetitive conduct.

2. Output Gap

The output gap is another metric we use to evaluate Duke's generation dispatch. The output gap is the output of an available generation resource that is unloaded when the prevailing market price exceeds the marginal cost of producing from that unit by more than a specified threshold. We use \$25/MWh and \$50/MWh as two thresholds in our analysis. Hence, at the $25/MWh threshold, if the prevailing market price is $60/MWh and a unit with marginal costs of $40/MWh is unloaded, then we do not consider this part of the output gap. However if the marginal cost is $30/MWh, we would consider it in the output gap at the $25/MWh threshold, but not under the $50/MWh threshold.

Figure 11 below shows the minimum daily output gap for the peak hours (hour ending 7 AM through hour ending 10 PM). The minimum is shown because the most liquid market is for a sixteen-hour block, and enough units must be committed to meet the peak hour of demand. As a result, it is necessary to keep some of the required units at part load during the hours with lower demand, resulting in an increase in the output gap. Only units that are committed during the day are included in the daily calculation. Hydro and nuclear units are also excluded.

For this analysis, we define the market price as the minimum between the Platts published VACAR price (discussed above) and PJM real-time prices at the AEP hub. We chose this composite price to ensure that if a portion of a unit's capacity were included in the output gap both day-ahead and real-time prices were taken into consideration. Theoretically, dispatch should be driven by real-time prices, but the timing of natural gas nominations and the limited liquidity in the real-time markets cause the day-ahead market to also be important for dispatch. The minimum daily output gap is used in the analysis, because this represents the quantity of power that could have been sold profitably on a sixteen-hour on-peak block schedule without having to commit additional units.

Figure 11: Minimum Daily Output Gap
January 2008 – March 2008

Redacted

The figure shows that the output gap occurred on four days at the $50/MWh threshold. Using the $25/MWhr threshold, the output gap occurred on 44 days. However, the most prominent feature is the spike in the output gap that occurred on January 1, 2008. Investigating further, we found that 747 of the 862 MW was accounted for by the [redacted] units operating at part load. We inquired further and found that the units were beginning their start-up process and happened to coincide with a price spike in PJM (at 1900, the prices went from below $30/MWhr to approximately $70/MWhr). The remaining values were small relative to the large number of generators on the Duke system. These results do not indicate evidence of anticompetitive conduct through the withholding of generation.

3. Generator Availability

We evaluate generator availability by examining the amount of capacity on outage as well as the ratio of capacity on outage to total capacity. In our first analysis, in Figure 12 we compare the average capacity on outage as well as the VACAR price and the prices of Duke short-term sales.

Figure 12: Outage Quantities
January 2008 – March 2008

Redacted

The figure shows that Duke sales prices and the market (VACAR) price are correlated, with a few exceptions. Some differences are expected because the Duke sales prices include day-ahead and real-time transactions while the wholesale prices reflect only day-ahead transactions. Our main interest is in generation outages that cause increases in market prices. Planned outages generally began to rise as expected temperatures increased towards the end of the quarter. The correlation between unplanned outages and prices is not immediately apparent from the chart. Therefore, we present this statistic below in Figure 14.

Figure 13 shows the average ratio of capacity in outage to total capacity (i.e. the average outage rate) and the VACAR price and the Duke short-term sales price. This chart reveals patterns similar to that revealed in Figure 12. The average forced outage rate over the study period was approximately [redacted] percent, which is low by industry standards.

Figure 13: Outage Rate January 2008 – March 2008

Redacted

Finally, the correlations of the average outage rates to the VACAR price and the short-term sales price are shown in Figure 14.

Figure 14: Correlation of Average Outage Rates with Wholesale Energy Prices January 2008 – March 2008

	Correlation with VACAR Index	Correlation with Duke Short Term Sales Prices
Scheduled Outages	8%	-4%
Unscheduled Outages	-11%	16%

While the figure reports both scheduled and unscheduled outages, the unscheduled ones are the most important from a market power perspective. Planned outages are expected and generally are scheduled in off-peak periods. Unscheduled outages can occur during peak times.

The positive correlation of the scheduled outage rate with VACAR index price is unexpected given that planned outages are typically scheduled during off-peak periods when prices are lower. However, during this time of year, outages are long enough to span both on and off-peak periods. There was also a positive correlation of the unscheduled outage rate with the short term sales prices. However, capacity on unplanned outage was included in the preceding evaluation of "Out-of-Merit Dispatch" and found not to significantly increase flow on congested paths. Thus, we find no evidence that generation outages were associated with anticompetitive conduct.

C. Analysis of Transmission Availability

Transmission outages are reviewed in order to determine whether they limit market access and, if so, whether they are justified. There were over 500 transmission outages that affected power flows on elements at 100 kV and higher during the period of study. Our review of these outages did not show that they led to curtailments, but there were cases where ATC was impacted.

The most notable effects on ATC were caused by the construction outage of the Robbinsville to Santeelah line. This outage followed (and is related to) last year's outage of the Nantahala to Robbinsville line. The outage affects TVA's side of the Duke to TVA interface, resulting in zero TTC and a zero ATC. It was necessary to rebuild these line segments in series in order to maintain supply to Robbinsville. Besides the planned line rebuild, there were two short-term forced outages of the Robbinsville to Santeelah line caused by breakers tripping open. There were nine TSR refusals associated with the outages on this interface. We did not find it necessary to further evaluate the planned outage because it was planned well in advance and, therefore, is unlikely to be the result of an attempt to exploit short term market conditions. The two forced outages are also not of concern because they lasted only a few hours and did not result in schedule curtailments.